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REBUTTAL TESTIMONY OF HETHIE S. PARMESANO

before the

Massachusetts Department of Telecommunications and Energy

D.T.E. 03-121

On behalf of

BOSTON EDISON COMPANY
CAMBRIDGE ELECTRIC LIGHT COMPANY
COMMONWEALTH ELECTRIC COMPANY
d/b/a/
NSTAR ELECTRIC

April 21, 2004

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I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Hethie S. Parmesano. My business address is 777 South Figueroa Street, Suite 4200, Los Angeles, California 90017.

Q. By whom are you employed and in what capacity?

A. I am a Vice President at National Economic Research Associates, Inc. (NERA). I serve as a consultant to utilities, regulators, and other stakeholders in the electric, gas and water industries in the U.S. and abroad.

Q. On whose behalf are you submitting rebuttal testimony in this proceeding?

A. I am submitting testimony on behalf of NSTAR Electric. In addition, Massachusetts Electric Company, Western Massachusetts Electric Company and Fitchburg Gas and Electric Light Company agree that the positions I set forth in my testimony reflect the proper approach and appropriate considerations in standby rate design, and have joined in supporting it.

Q. Please describe your education and professional background.

A. My B.A. is from Colby College, where I majored in economics. I have M.A. and Ph.D. degrees in economics from Cornell University. Since 1980 I have worked for NERA, specializing in utility costing, pricing, strategic planning and regulatory reform. I have testified widely on these matters. Since the establishment of regulations implementing PURPA in the early 1980s, I have been involved in numerous proceedings and projects related to non-utility generation, including standby rates. Recently I have published two pieces on this topic in *Electricity Journal,*[1] both of which are included in Exhibit NSTAR-HSP-2. For more than two decades I have taught classes for utilities and regulators on marginal costing and rate design. I also direct NERA's Marginal Cost Working Group, a utility group that is dedicated to improving methods for estimating and using marginal cost information in a variety of utility applications. Exhibit NSTAR-HSP-3 contains more details on my credentials.

Q. Have you previously testified before the Department?

A. I have not previously testified before the Department; however, I have testified on utility rate matters before regulatory authorities in 24 other jurisdictions.

Q. What is the purpose of your testimony in this proceeding?

A. In order to put some of the intervenors' direct testimony in perspective, NSTAR Electric asked me to describe: (i) the potential benefits of distributed generation (DG); (ii) the issues raised by using standby rates to encourage beneficial DG development; and (iii) the elements of efficiently designed standby rates. I will address specific statements in intervenor direct testimony and conclude with some general comments on NSTAR Electric's proposal.

[1] "Standby Service to Distributed Generation Projects: The Wrong Tool for Subsidies" The Electricity Journal, October 2003; and "Standby Rates Issue Is More Nuanced Than Authors Let On," Letter to the Editor, The Electricity Journal, November 2003.

Q. Please summarize the main points in your rebuttal testimony.

A. Many of the intervenors in this case oppose NSTAR Electric's proposed standby rates because these rates will increase the cost of standby service to some DG projects compared to current rates. They argue that standby charges should be kept low because DG provides benefits to society at large. Although it is correct that some DG projects may provide benefits beyond those that accrue to their developers and operators, below-cost standby rates are a blunt tool for this job because they give incentives to both socially beneficial and non-beneficial DG projects. In addition, subsidized standby rates distort the design and operation of the DG projects, can lead to inefficient distribution investment by the utility, and improperly shift costs to other customers. Like all distribution rates, standby rates should be based on the costs of providing service. Setting standby rates that give appropriate price signals to DG requires (i) an examination of the way the distribution system is designed and (ii) consistency with the way non-DG customers are charged. NSTAR Electric's proposal to use its non-DG rates as a starting point and recover non-customer-related distribution costs in a monthly contract demand charge for DG facilities of at least 1 MW and a combination of contract demand charges and monthly demand charges for smaller facilities is consistent with the way costs are incurred to serve DG standby loads on the Company's distribution network.

The test of whether the design of a standby rate is appropriate should not be whether it discourages some potential DG projects, but rather, whether it is a reasonable mechanism to recover the costs of (1) standing by to provide service; and (2) delivering energy when the DG experiences an outage. Put simply, not all DG projects should be built.

II. BENEFITS OF DISTRIBUTED GENERATION

Q. Does DG have the potential to provide benefits beyond those that accrue to the owner of the facility?

A. Yes. In certain circumstances, DG can provide general benefits. For example, in a competitive wholesale market, DG can increase competition and lower market prices, particularly in load pockets. Depending on technology, DG may reduce air pollution and increase fuel diversity. DG-produced energy that is delivered locally can relieve congestion on the transmission system and lower energy costs. DG may also reduce loading on the distribution network. Very reliable DG may enable the utility to defer transmission and distribution capacity expansion. However, as discussed by Mr. Salamone, under normal circumstances the addition of DG on a circuit does not permit a prudent utility planner to defer local circuit expansion, and distribution substations must be designed to accommodate the full load of large DG projects.

Q. Your previous answer is qualified. Is it your testimony that not all DG projects provide these benefits?

A. Yes. The benefits depend upon the specific characteristics of each individual project, which vary widely.

Q. Do the intervenors acknowledge the great diversity in DG projects?

A. Yes. For example, CLF/SEBANE witness Michelman explained that because of wind variability and limitations of modern wind turbines, "the monthly peak metered demand post DG wind installation likely will be equal to or within 5 percent of the monthly peak metered demand pre DG wind installation" and that "the exact effect for any specific customer depends upon characteristics of customer load, wind resources, and type and size of wind turbine installation" (pp. 3-4). Thus, the limited energy production by wind turbines is unlikely to provide reliable load reductions that would enable the utility to defer capacity expansion.

In contrast to the operating characteristics of a wind turbine, the combined heat and power (CHP) systems described by NEDGC witness Vardakas operate as baseload units at a fairly uniform level all year (p. 3), with "heat dissipation units to reject heat during the summer peak periods when thermal needs may be limited" (p. 8). However, these "machines must be shut down for oil changes and other maintenance at least once each month....Other outages occur from equipment malfunctions, including occasional building heating system problems" (p. 8).

Another NEDGC witness, Mr. Casten, installs "heat-first combined heat and power," which means that their "generators operate only when there is a need for low-grade heat. In most cases, this means that our systems produce maximum power during the winter months, although this is not universally true" (p. 4). These systems will not provide the same benefits as similarly sized, highly reliable, baseload DG projects, because they will not be operating at full capacity during summer peak hours. Mr. Casten also mentions (p. 10) that NSTAR Electric's proposed standby rate will have different impacts on different technologies, such as "peaky" solar projects, presumably because of their very different operating characteristics.

Q. Does the intervenor testimony reveal other important ways in which DG projects differ from each other?

A. Yes. Another difference that struck me, reading the intervenors' testimony, is their appetite for rate complexity and their ability to respond to price signals. Mr. Vardakas opposes what he sees as the complexity of NSTAR Electric's proposed rate, noting that "[t]he typical mid-size customer does not understand their current billing. Only some know of demand charges, which are feared because they cannot control their loads, or on and offpeak kilowatt-hour charges which usage they cannot do anything about, and other charges that they do not have time to learn about" (p. 6).

In contrast, NEDGC witness Casten believes that NSTAR Electric's proposal "will effectively prevent customers from fully participating in the restructured energy market," (p. 8) which suggests that he believes DG owner/operators want to respond to constantly changing market prices. Another NEDGC witness, Mr. Smith, echoes this position when he states his opposition to NSTAR Electric's proposed demand ratchet for distribution costs because it would result in "no price signals that can influence us to adjust behavior to actual market conditions" (p. 7).

Joint Supporters witness Lively favors an extremely complex arrangement of "dynamic tariffs" that would, apparently, set a price for the distribution portion of standby service using "a system of formulas that relate marginal distribution cost to measurements on the

NSTAR system and to externally determined prices of electricity." (p. 22). This unprecedented approach to standby rates could produce a different price on each circuit and a different price in each hour. As I understand Mr. Lively's proposal, the hourly real-time prices would have to be communicated to DG customers so that they could decide whether to use standby service or cut load.

Q. What is the implication of these examples from the testimony of DG advocates in this case?

A. These differences highlight the extreme diversity of DG projects and the difficulty in tailoring standby rates that will work for all. Net metering already provides simplicity for projects less than 60 kW. Special situations for very large, very sophisticated, and very reliable projects (or groups of projects on a single circuit) could perhaps be handled with individual contracts. If such DG operators are willing to make appropriate and enforceable assurances that their generation units will not require standby service during peak conditions on the local distribution system, it may be appropriate for the utility to enter into a special contract with the DG customer to reflect the value of the DG project on the network. There will likely be many other projects with a wide range of standby requirements. These projects need standby rates that signal to them the costs of providing standby service – both in terms of maintaining the necessary infrastructure and delivering the energy when the customer's generator is not producing at the normal level. The current structure of rates for customers without generation does not provide these signals.

Q. You have indicated that some DG projects provide benefits beyond those accruing to the owner and operator of the project. What is the appropriate way to recognize these benefits?

A. Economists refer to benefits to the general public that accrue from the actions of a private decision-maker as "external benefits." There are also numerous cases of "external cost" resulting from a private decision that are imposed on the general public. The classic example of external costs is unregulated pollution. In situations where government authorities consider the external costs or external benefits to be significant, laws and regulations are established that change the external costs and benefits to internal costs and benefits for the private decision maker. Requiring businesses to purchase allowances to emit substances into the air or water changes pollution from an external cost to an internal cost for the business.

It is clear that some DG projects provide some external benefits. Standby rates may be a tempting mechanism for converting these external benefits to internal benefits for the DG owner/operator, because a policy on discounted standby rates can be easier to implement than imposition of a new tax or an allocation of existing scarce state revenues for this purpose. However, mechanisms that provide direct incentives based on the specific benefits provided by a given project are a much more efficient way to encourage beneficial projects.

Q. Have some states taken the approach of direct incentives to beneficial DG?

A. Yes. In fact, most states offer some direct assistance to DG. The table on Exhibit NSTAR-HSP-2, pp. 3-4, illustrates the types of programs offered by each state as of early 2003. DG projects in Massachusetts benefit from net-metering if less than 60 kW, and tax benefits and grants are available to qualified renewable projects. As NEDGC witness Casten indicates, the Massachusetts "legislature has created a Renewable Energy Trust, collected by a surcharge on electric ratepayers, that seeks to encourage the development of distributed generation" (p. 9). NEDGC witness Smith states, "In general, the CHP market in Boston seems favorable. The state and local government agencies are helping to promote CHP. There are also incentives available for installing efficient combined heat and power systems" (p. 5).

In addition, as the intervenors in this case recognize, there are a number of other ways that DG projects, particularly renewable projects, internalize what would otherwise be external benefits. Revenues from the sale of emissions credits and growing markets for "green certificates" to demonstrate compliance with renewable portfolio standards internalize these benefits of DG. SEBANE witness Greene states that in Massachusetts, factors driving large scale PV development include "renewable portfolio standards, state buy-down funds targeted to PV projects, state tax credits and tax exemptions, retail choice/green power markets, emission allowance set-aside programs, and electricity labeling" (pp. 20-21).

Thus, in Massachusetts and elsewhere, government agencies are offering a broad range of incentives to DG that convert external benefits to revenues for the developers and operators of these projects.

Q. Should standby rates be reduced below the cost of providing standby service to reflect the benefits provided by DG?

A. Absolutely not. Subsidized standby rates are the wrong tool for encouraging DG. Any benefits that are not directly related to utility cost savings should (or already are) being addressed by other government policies. Joint Supporters witness Lively appears to agree that standby rates are not the right mechanism for reflecting such benefits: "Distributed generation can provide a benefit to the utility's entire customer base, but that is not the issue in this proceeding" (p. 8).

Q. Why are standby rates the wrong tool for encouraging beneficial DG?

A. There are two key reasons. First, the cost and structure of standby service charges influence many aspects of DG design and operation. For example, prudent operators of DG will take into consideration the cost of standby service when they make decisions such as whether to design the generator to work as a baseload or peaking resource, how often and when to do maintenance, whether to cut load when the generator is down to minimize standby load, what size connection to request from the utility, whether to shut down the generator when market prices of energy are lower than their operating costs, and whether to purchase standby service or provide their own backup. If the price of standby service is discounted to encourage DG development, these decisions will be distorted to the detriment of society at large.

The second key reason why standby rates are the wrong tool for encouraging beneficial DG is that the incentives of subsidized standby service go to all DG projects – not just those that are providing the benefits. Incentives specifically targeted to projects that reduce air pollution, or increase fuel diversity, or promise highly reliable operation in a location that would reduce network congestion, or offer other specific benefits are a much more effective way to ensure that the good projects are built. As I stated earlier, not every potential DG project should be built, even though this may mean the loss of some business for companies such as those represented by some of the intervenors.

III. FEATURES OF PROPERLY DESIGNED STANDBY RATES

Q. What are the features of properly designed standby rates?

A. As in the development of other regulated utility rates, standby rates should be designed to reflect the cost of providing standby service (i.e., be cost-based). It is my understanding that in Massachusetts, the Department's policies require distribution rates that take into account a number of factors, including fairness among customer classes, economic efficiency and the cost to serve.

As several intervenors have pointed out, the difference in a customer's electricity bill before and after installation of DG is one of the factors that determine whether a particular DG project is financially feasible. To comply with the Department's policy on economic efficiency, standby rates must be designed by starting with the otherwise applicable rate schedule. The standby rate and the otherwise applicable rate are thereby consistent and both based on the same cost principles. When standby rates are developed in this manner, customers facing a decision whether to invest in DG will make economically efficient decisions based on an unbiased comparison of the cost of available alternatives.

To comply with the Department's policy on fairness among customer classes and cost of service, standby rates must also be designed so that costs of providing standby service are recovered from standby customers and not shifted to other customers. Use of monthly metered demand charges will not allow the distribution company to recover costs incurred to provide the local distribution facilities needed to "stand by" for the DG customer. Such costs must be recovered through a contract demand charge.

Q. What is the structure of the cost of providing standby service to DG?

A. The cost structure of providing standby service to DG is essentially the same as the cost structure of providing service to customers without generation. Generation and transmission costs of standby service are not at issue in this case, so I will confine my comments to distribution costs. These costs consist of: (1) the costs of hooking an individual customer to the network (meter, meter-related facilities and service drop), (2) costs of local shared facilities (generally secondary and primary facilities) that must be sized based on the customers' maximum expected loads (or contract demands) over the life of the facilities, and (3) costs of facilities (typically substations) which are sized on the basis of near-term expected local peaks and can be expanded as needed. Exactly how facilities are split into the latter two categories can be different for customers of different sizes and voltage levels and in different locations. In addition, there are per-customer costs associated with meter reading, billing, customer accounting, and customer information services.

Q. How should the three categories of distribution costs be reflected in the rate structure?

A. Cost-based distribution charges for DG (and any customer group) should ideally consist of: (1) a fixed monthly customer charge to recover hook-up costs and customer-related expenses; (2) a local facilities charge levied per kW of contract demand to cover the average cost of the local facilities sized on the basis of long-term potential local peak demand (contract demand); and (3) time-differentiated charges based on use to recover the average costs of distribution facilities (such as substations) that are typically sized based on near-term expected local peaks and can be expanded as needed.

There is an important exception with regard to this third category of costs in the cases where (1) a single DG facility (or other large customer with intermittent load) constitutes a significant part of the load on these facilities and (2) a group of DG facilities served by a particular substation may all need delivery of standby power simultaneously. In these cases, there may be no costs in the third category; even substation costs may fall into the local facilities category.

Q. Does a cost-of-service study need to be performed in order to identify the most accurate cost to provide standby service?

A. Yes, of course a cost-of-service study is required to identify the *most accurate cost* of providing any utility service. However, in the absence of new cost information and a new set of rates for all utility services, using the current non-DG rates (which were based on Department-approved cost studies in the past) as a starting point for new standby rates is a reasonable approach and is consistent with sound rate-setting policies. As I explained earlier, to encourage development of economically efficient DG projects and to avoid shifting costs to non-DG customers, it is critical that the electricity bills before and after installation of the DG equipment reflect, as closely as possible, the difference in the cost of providing the required service before and after that installation. As long as the non-DG rates have not be reset based on new cost-of-service information, setting standby rates based on current non-DG rates is the best available option.

Q. Several intervenors have argued that distribution costs should not be recovered from DG customers on the basis of contract demand because the likelihood of their requiring standby service at the time of the system peak is very small. For example, NEDGC witness Smith says, "one would expect a high degree in [sic] peak usage diversity among CHP systems in different locations because CHP systems by their nature are not inter-dependent." (pp. 8-9) Why doesn't your prescription for distribution rate design take this probability into account?

A. There are three reasons. First, the distribution system is not designed to meet system peak; it is designed to meet local peaks. And local peaks are not simultaneous. It is the effect on local capacity needs that must be taken into account in setting distribution charges for DG. The diversity of DG standby loads scattered around the entire system does not reduce the cost of providing distribution service to a DG installation on a particular circuit.

Second, just because a particular DG facility is expected to operate 95 percent of the hours of the year does not mean that distribution planners can safely assume that the DG's random outages in the other 5 percent of hours will occur when there is surplus capacity on the local distribution circuit. To do so would put service reliability to all customers on that circuit at risk.

Third, even when there are multiple DG facilities on the same circuit, there may be little diversity of their standby requirements. For example, if they all use the same technology (solar and the sun is not shining, wind and the wind is not blowing, gas-fired and there are problems with gas supply), they may all need standby service at the same time. Or they may all decide to shut down their generators and instead purchase energy if the market price of energy falls below their operating costs.

Q. What is your response to some intervenors who claim that the use of an annual contract demand charge is an inefficient ratchet?

A. Ratchet designs may be efficient – if the costs recovered in the ratcheted charge are also incurred on that basis – or inefficient. Terming a rate design a ratchet does not provide one with any insight as to whether it is desirable or not. Whatever NSTAR Electric's proposed contract demand charge may be called, it is the most appropriate mechanism for recovering the local distribution costs (and substation distribution costs) of serving standby customers. Mr. Salamone's discussion of NSTAR Electric's local distribution costs in his rebuttal testimony further supports this conclusion.

Q. What would be the result of recovering local distribution costs from standby customers in a monthly demand charge rather than a contract demand charge?

A. The result would be underrecovery of distribution costs from standby customers. Although the facilities are in place to serve them every month, they would pay only in months when they experienced a generator outage. This result would be neither efficient nor fair from the perspective of all customers.

IV. NSTAR ELECTRIC'S PROPOSAL

Q. Is NSTAR Electric's treatment of distribution costs in its standby rate described in Mr. LaMontagne's rebuttal testimony consistent with your prescription for recovery of these costs?

A. Yes. Mr. Salamone has described how NSTAR Electric performs distribution system planning. The Company's proposal to recover all non-customer-related distribution costs in a monthly charge per kW of contract demand for DG customers with generators of at least 1 MW and a combination of contract demand charges (for local distribution facilities costs) and monthly peak demand charges (for distribution substation costs) for smaller DG customers is consistent with the way distribution costs are incurred, and will signal to DG customers the Company's cost of standing by to provide distribution service when called upon.

V. CONCLUSIONS

Q. What conclusions should the Department draw from your testimony?

A. Some DG projects provide benefits beyond those that accrue to their developers and operators, and there is a role for government to provide coordinated incentives to encourage those projects to be built. However, below-cost standby rates are a blunt tool for this job because they give incentives to both socially beneficial and non-beneficial DG projects. In addition, subsidized standby rates distort the design and operation of the DG projects, can lead to inefficient distribution investment by the utility, and shift costs to other customers. Standby rates should be based on the costs of providing standby service. In the case of distribution, this requires an examination of the way the distribution system is designed. NSTAR Electric's proposal to recover non-customer-related distribution costs in a monthly charge per kW of contract demand for DG facilities of at least 1 MW and a combination of contract demand and monthly demand charges for smaller projects is consistent with the way the Company plans for DG standby loads on its distribution network. The test of whether a standby rate is appropriate should not be whether or not it discourages some potential DG projects, but rather whether it recovers the costs of (1) standing by to provide service and (2) delivering energy when the DG experiences an outage.

Q. Does this complete your prefiled rebuttal testimony?

A. Yes, it does.